

# Transmission Planning and the Need for New Capacity

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# Transmission Planning and the Need for New Capacity

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## Introduction

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The U.S. electricity industry is in the midst of a transition from a structure dominated by vertically integrated utilities regulated primarily at the state level to one dominated by competitive markets. In part, because of the complexities of this transition, planning and construction of new transmission facilities are lagging behind the need for such grid expansion.

Between 1979 and 1989, transmission capacity increased slightly faster than did summer peak demand (Hirst and Kirby 2001). However, during the subsequent decade, utilities added transmission capacity at a much lower rate than loads grew. The trends established during this second decade are expected to persist through the next decade. According to one analysis, maintaining transmission adequacy at its current level might require an investment of about \$56 billion during the present decade, roughly half that needed for new generation during the same period (Hirst and Kirby 2001).

Expanding transmission capacity requires good planning (as well as appropriate market rules and regulatory oversight). The Federal Energy Regulatory Commission (FERC 1999) emphasized the importance of transmission planning in the creation of competitive wholesale markets. FERC wrote that each regional transmission organization (RTO) “must be responsible for planning, and for directing or arranging, necessary transmission expansions, additions, and upgrades that will enable it to provide efficient, reliable, and non-discriminatory transmission service and coordinate such efforts with appropriate state authorities.” FERC included transmission planning as one of the eight minimum functions of an RTO:

[T]he RTO must have ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service... . The rationale for this requirement is that a single entity must coordinate these actions to ensure a least cost outcome that maintains or improves existing reliability levels. In the absence of a single entity performing

these functions, there is a danger that separate transmission investments will work at cross-purposes and possibly even hurt reliability.

This shift from planning conducted by individual utilities for their system to meet the needs of their customers, to planning conducted by RTOs to meet the needs of regional electricity markets, raises important issues (Table 1). These issues include the criteria for planning (reliability, economics, etc.); environmental considerations (effects of transmission expansion on the location and types of emissions from power plants, accommodation of remotely located renewable resources, as well as the direct siting and environmental effects of transmission); economic development (providing greater access to cheaper power may encourage local and regional economic growth); the role of congestion costs in deciding which projects to build; the consideration of generation, load, and transmission-pricing alternatives to new transmission projects; the economic and land-use benefits of building larger facilities ahead of immediate need; the role of new solid-state technologies that permit operation of transmission systems closer to their thermal limits; the role of merchant transmission projects; and the growing difficulty in obtaining data on new generation and load growth caused by the separation of generation and retail service from transmission. Finally, collaborative transmission-planning processes, which include various stakeholders early in the process (e.g., as problems are being identified rather than when solutions have already been selected), should be considered as RTOs plan for future regional electricity needs.

Part of the complexity associated with transmission planning stems from transmission's central position in electric-system operations and wholesale power markets. Because of its centrality, transmission serves many commercial and reliability purposes. American Transmission Company (2001) identified several objectives for transmission planning and expansion: improve transfer (import and export) capability from different directions, accommodate load growth without delay, accommodate generation development without delay, provide flexibility to transmission customers to modify their transactions as market conditions change, reduce service denials and interruptions due to transmission constraints (equivalent to reducing congestion costs), cut losses, and improve reliability. Southern Company Services (1995) mentions many of the same objectives and also includes provision of sufficient margin to permit transmission elements to be taken out of service temporarily for maintenance.

The American Transmission Company (2001) plan notes some of the many issues it will have to consider as it plans for transmission expansion, including public involvement in the planning process, minimizing environmental and land-use impacts, timely licensing and construction of good projects, and balancing the robustness of the transmission system with the need to keep transmission rates reasonable.

The foregoing comments on the purposes and complexities of transmission planning emphasize the fact that such planning is only one element of a broader process that ultimately leads to the construction of needed bulk-power facilities (Fig. 1). To assess various transmission and nontransmission (generation, load, and pricing) alternatives, transmission models require large amounts of data and projections related to loads, generation, and transmission. Transmission planners use detailed electrical-engineering computer models to assess these alternatives (Fig. 2). Model results, combined with information on project costs, environmental effects, siting, and regulatory requirements, lead to financial and regulatory assessments of different projects. Ideally, these plans lead to the construction of needed projects, cost recovery (including a return on investment) for transmission owners, and transmission rates that appropriately charge users for the services they receive.

**Table 1. Key transmission-planning issues**

Topic	Issues
Reliability vs commerce	To what extent should RTOs plan solely to meet reliability requirements, leaving decisions on grid expansion for commercial purposes (e.g., to reduce congestion costs) in the hands of market participants?
Congestion costs	Are congestion costs (e.g., short-term nodal or zonal congestion prices and long-term firm transmission rights) a suitable basis for deciding on transmission investments?
Alternatives to transmission	What role should RTOs play in assessing and motivating suitably located generation and load alternatives to new transmission? Should RTOs provide information only or should they also help pay for such alternatives?
Economies of scale	Should RTOs or private investors overbuild transmission facilities in anticipation of future need to reduce the dollar and land costs per GW-mile of new transmission facilities? How should these economies be balanced against the possibly greater financial risks of larger transmission facilities?
Advanced technologies	What are the prospects for widespread use of new technologies (e.g., superconductivity, solid-state electronics, and faster systems to collect and analyze data) to improve system control, thereby permitting operation of existing grids closer to their limits?
Planning data	Who will provide the data needed for transmission planning, particularly on the locations, timing, and types of new and retiring generating units and the loads and load shapes of retail customers?
Economic effects	How should transmission's impact on regional power prices and the resulting impact on the regional economy be factored into transmission planning?
Environmental and other societal effects	How should the effects of transmission availability on the generation mix and the resulting shift in emissions be included in transmission planning? How should remotely located generators (e.g., coal and wind) be accommodated in transmission planning? Should transmission be built to increase fuel diversity for generation and to discipline generator market power? How should potential siting problems be incorporated into the planning process?
Centralized vs decentralized transmission planning and expansion	To what extent can private investors, rather than RTO planners, decide on and pay for new transmission facilities? Can they, in spite of network-externality effects, capture enough of the benefits of such transmission projects to justify their investment? How can new technologies advance private investment?

Figure 1. Transmission-planning models, and their inputs and outputs.

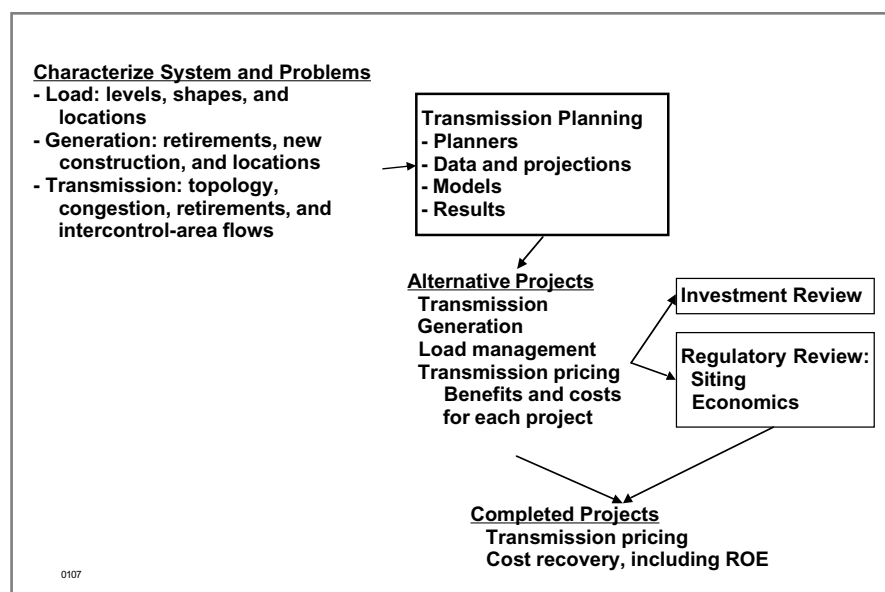


Figure 2. The relationship between transmission planning and its inputs (data and projections) and results.

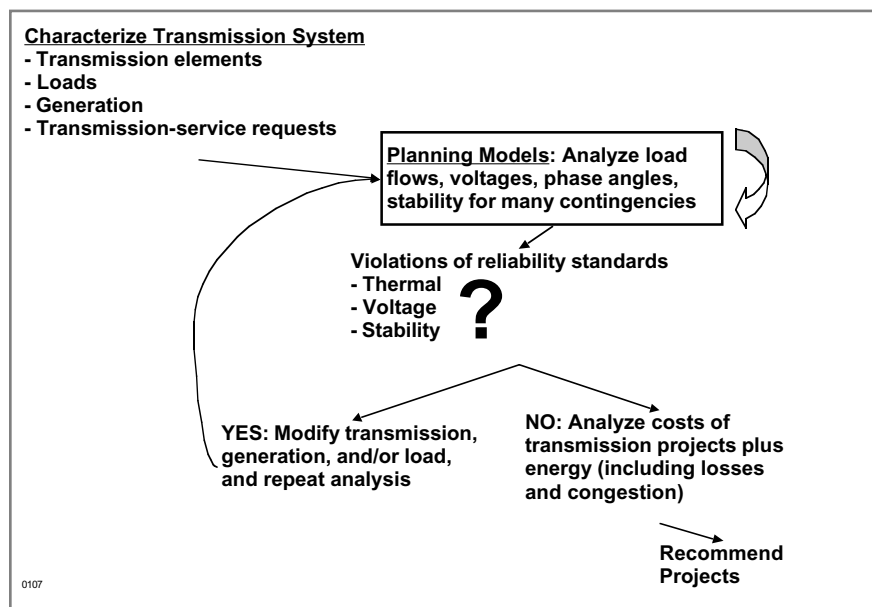


Figure 2 expands on the transmission-planning portion of Fig. 1. This second figure shows how load-flow, dynamic, and short-circuit models are used to determine whether the bulk-power system can meet all the applicable operating and planning reliability standards. The arrow to the right of the box labeled Planning Models indicates that these models are run over and over to test the ability of the bulk-power system to operate within specified ranges for all first- and some multiple-contingency conditions.

The fundamental characteristic that makes transmission planning and investment so difficult is lack of control of the grid and the inability to control the flow through individual transmission elements (e.g., lines and transformers). (Devices such as phase shifters and direct current (DC) links allow control, but are much more expensive than traditional transmission facilities.) Each transmission element is part of a network that is a common resource available to all. Because electricity flows according to the laws of physics and not in response to human controls, what happens in one part of the grid can affect users throughout the grid. Because of these large externalities, transmission must be centrally managed and regulated. Other characteristics that complicate transmission planning include:

- **Large Geographic Scope**—Conditions on one part of an alternating current (AC) network affect flows throughout the network. Consequently, transfers between any two points on the network can be restricted by constraints elsewhere in the network. Similarly, upgrades to any part of the network affect transfer capabilities throughout the network.
- **Diversity of Interests**—Each transmission enhancement affects many market participants. Generators will either expand their market opportunities (if they are low-cost producers) or reduce their market opportunities. Loads have similar, but opposite, interests.
- **Transmission vs Generation**—The split and differences between competitive generation and regulated transmission affect transmission planning. The competitive generation business encourages faster planning, shorter deployment times, and less sharing of commercially sensitive information. The regulated transmission business environment produces slower planning and longer deployment times (to accommodate an inclusive public process) and the wide sharing of information. In addition, transmission and generation are both complements and substitutes. As a consequence, poor transmission planning and inefficient transmission expansion could undercut competitive wholesale markets and increase electricity costs.
- **Long Life**—Transmission is a long-lived (30 to 50 years), immobile investment with very low operating costs. The need for new transmission shows up in real-time congestion prices. It is difficult to accurately forecast the need for a specific transmission investment for several decades. The generation and demand-side alternatives are often shorter lived and have higher operating costs that can be eliminated if the investment is no longer needed.
- **Regulatory Decision Process**—Because the regulator (and the regulated entity) are spending ratepayer dollars, public processes are used to produce good decisions. All opinions and options are welcome and considered, which can lead to a time-consuming and costly process.
- **Regulatory Uncertainty**—Investors are unlikely to spend their money until it is clear that they will recoup their investment and earn a reasonable return on that investment.
- **Environmental Impacts**—Some people oppose new transmission lines (and, to a lesser extent, substations) on aesthetic grounds or because they might lower property values. Others are concerned about the health effects of electromagnetic fields. Although little

scientific evidence supports this concern about transmission lines, public perceptions and fears may lead to opposition to construction of new transmission lines (National Institute of Environmental Health Sciences, 1999).

The remainder of this issue paper is organized as follows: The next section summarizes planning processes as practiced by vertically integrated utilities and today's independent system operators (ISOs). This section also summarizes the planning processes proposed by RTOs. Subsequent sections outline the characteristics of an ideal transmission plan and planning process; a benchmark against which current and future plans might be assessed; and several key planning issues and the complications that arise because of the increasing competitiveness and transitional state of the U.S. electricity industry. A later section recommends certain actions for DOE, FERC, and others on improved planning processes; while the final section summarizes the key findings from this issue paper.

## **Transmission Planning Practices**

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### **Traditional Utilities**

Historically, transmission planning was much simpler than it is today and than it is likely to be in the future. Until the mid-1990s, the U.S. electricity industry featured vertically integrated utilities. As a consequence, transmission planning was closely coupled to generation planning. Utilities, because they owned generation and transmission, could optimize investments across both kinds of assets. With respect to operations, utilities routinely scheduled generation day-ahead and redispatched generating units in real time to prevent congestion from occurring. The costs of such scheduling and redispatch were spread across all customers and reflected in retail rates.<sup>1</sup>

In addition, utilities had good data and forecasting tools to estimate current and future loads and generating capacity. Because each utility was the sole provider of retail electricity services, it had considerable information on current and likely future load levels and shapes. Because each utility was the primary investor in new generation, it had considerable information on the timing, types, and locations of new generation and corresponding information on the retirement of existing units.

Finally, the amount of wholesale electricity commerce was much less than it is today and it was much simpler. It was simpler in the sense that most transactions involved neighboring utilities, either to take advantage of short-term economies of operation or for long-term purchases of firm power.

### **Current Planning Environment**

In today's electricity industry, generation and transmission are increasingly separated, either through functional unbundling of these activities or through corporate separation. This deintegration, combined with the competitive nature of electricity generation, makes it much harder for transmission planners to coordinate

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<sup>1</sup>Although transmission planning focused primarily on generation and loads within a single control area, the tight power pools and regional reliability councils reviewed utility plans to ensure that projects proposed in one service area would not adversely affect other utility service areas.

their activities with those of generation owners. In particular, the owners of generation are reluctant to reveal their plans for new construction and retirement of existing units any sooner than they have to.

In some regions, today's system operators are independent of load-serving entities. Therefore, the system operators have little information on the details of retail loads, such as the types of end-use equipment in place and trends and patterns in electricity use. It is now the load-serving entities that have such information, and for competitive reasons, they may be reluctant to share such information and projections with the system operator.

This deintegration of generation and transmission means that congestion management is no longer an internal matter. Of necessity, congestion management involves a system operator, transmission owners (if different from the system operator), power producers, and load-serving entities.

The separation of generation from transmission can lead to investment decisions in both sectors that are sub-optimal from a broad societal perspective. For example, more than 8000 MW of new generating capacity plan to interconnect to the Palo Verde substation in Arizona (Emerson and Smith, 2001). But the existing transmission system can handle no more than 3360 MW of new generation. Even with the three new 500-kV lines proposed for this area, the maximum export capability will be only 6750 MW because of stability limits, well below the 8000 MW planned. To make the problem even worse, most of these new generators will obtain natural gas from the same pipeline. Thus, the outage of this pipeline could become the single largest contingency in Arizona, increasing greatly the amount of contingency reserves that must be maintained.

Finally, the amount and complexity of wholesale electricity commerce is much greater than it was a few years ago. Transactions today can span several control areas, and ownership of the power may change hands several times between the point of injection (the generator that produces the power) and the point of withdrawal (the load that consumes the power). This complexity makes it difficult for system operators to know the details of transmission flows and even more difficult to project what these flows might be like in future years.

## **Review of Recent Plans**

Independent System Operators (ISOs) and utilities are developing transmission-planning processes to accommodate the needs of a rapidly evolving and increasingly fragmented electricity industry. This section briefly reviews several plans recently issued by ISOs and other regional entities.

The Electric Reliability Council of Texas (ERCOT) (2001) plan discusses historical and projected generation and load by region within ERCOT, including a range of projections. These projections form the basis for an identification of existing and likely future transmission constraints within the Interconnection and of an assessment of the need for additional transmission. The ERCOT report includes a discussion of existing transmission capacity and expansion possibilities for each of the three ERCOT subregions.

Overall, the ERCOT plan identifies six major transmission constraints (generally thermal limits, but sometimes stability limits). The plan also identifies several projects intended to mitigate these constraints. These projects include several 345-kV lines (both new lines and additional circuits on existing towers), a static compensator

(to provide dynamic reactive-power support), and capacitors (to provide static reactive-power support). In addition, the transmission owners proposed several projects, which ERCOT recommended for construction.

One indication of the success of the ERCOT transmission-planning process is the number of transmission projects recently completed or under construction. ERCOT has several transmission advantages over other regions, including regulation by a single entity (the Texas PUC), a state government that supports additional transmission, and a regulatory system that gives transmission owners a reasonable assurance that their capital investments will be recovered. Of the seven projects considered critical during the past few years, one was completed in 2000, five are on schedule to be completed by the end of 2002, and one is undergoing further evaluation (Texas Public Utility Commission 2001).

The goals of the Mid-Continent Area Power Pool (MAPP) (2000) plan are to ensure that the transmission system can “reliably serve the load indigenous to the MAPP region,... provide sufficient transfer capability to reliably accommodate firm transfers of power among areas within MAPP and between MAPP and adjacent reliability regions, and provide an indication of transmission costs for enhancing transfer capability and relative costs for alternative locations of new generation.” The MAPP process is bottom up, with plans developed by individual transmission owners, then integrated for each of the five subregions, and then integrated again at the MAPP level. In addition, considerable analysis is done for the MAPP region as a whole, primarily to analyze projects that span more than one subregion. The MAPP review ensures that projects proposed in one subregion will not adversely affect the electrical system in other subregions. Although MAPP planning still relies heavily on the individual utilities, the regional planning process is beginning to significantly influence the individual expansion plans.

The MAPP plan uses information on transmission service requests that were refused along with data on transmission curtailments to help in the analysis of “desired market use of the regional and inter-regional transmission system.” These data “provided strong evidence to indicate that transmission constraints to the east of MAPP significantly hampered electrical sales” (Mazur, 1999).

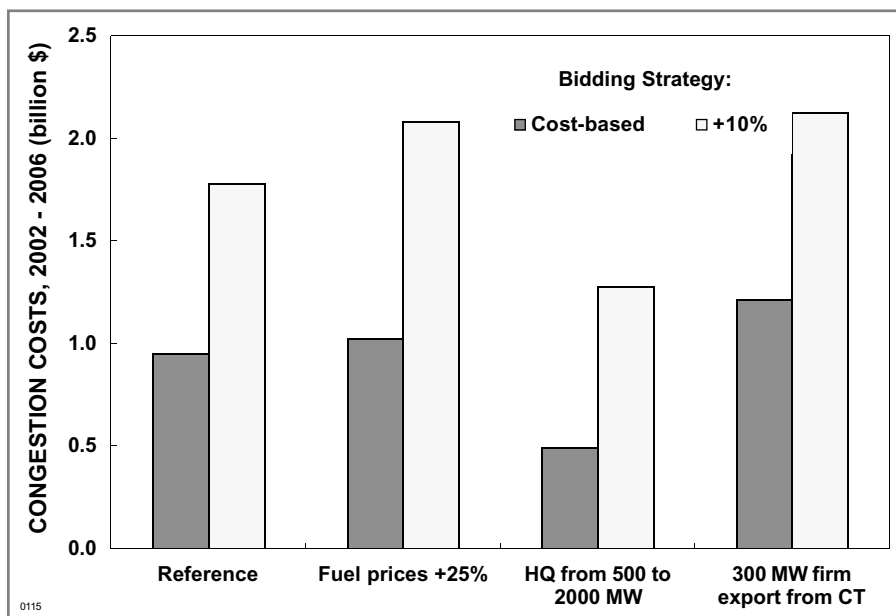
The ISO New England (2001) plan breaks new analytical ground. This plan explicitly analyzed the potential benefits of new transmission from reductions in congestion through what the ISO calls its Projected Congestion Cost Assessment, “which, through modeling, determined the economic costs associated with transfer limits between regions and separately analyzed the New England system on a bus by bus basis for transmission constraints.” As the report notes, “Significant transmission congestion will exist from an economic viewpoint, primarily between ME/NH [Maine and New Hampshire] and Boston, SEMA-RI [Southeast Massachusetts] and both Boston and SWCT [Southwest Connecticut]. Estimates of New England congestion range between approximately \$200-\$600 million per year during the study period, depending on the assumptions utilized.”

The New England analysis also considered the effects of market power on congestion costs, which could have enormous effects on the benefits associated with new transmission facilities. Because analysis of strategic market behavior is difficult, the New England analysis used a simple approach: it increased the bid prices for all generators by 10 or 25% above their marginal operating costs.<sup>2</sup> This approach may underestimate the

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<sup>2</sup>The traditional assumption in production-costing models that generators bid their marginal costs is almost surely incorrect. On the other hand, appropriately simulating bidder behavior, with and without new transmission that expands the scope of regional markets and reduces congestion, is very difficult.

Figure 3. Congestion costs in New England under different assumptions about fuel prices, Hydro Quebec imports, and exports from Connecticut, as well as the bidding behavior of generators.



benefits of transmission in reducing the ability of generators to exercise market power.

Figure 3 is a summary of some of the congestion-analysis results developed by ISO New England. The graph shows how sensitive these estimates are to different assumptions. And this is just a subset of the cases ISO NE examined; the 5-year congestion costs for the full set of cases ranged from about \$500 million to more than \$3 billion.

Because this was just an ini-

tial assessment, it includes no estimates of the costs to build the transmission needed to relieve congestion in the region.

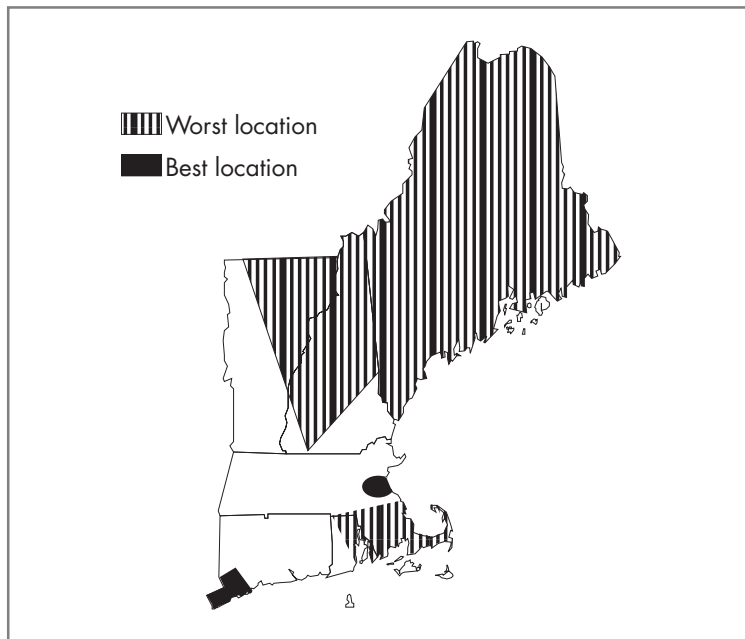
ISO New England divided the region into 13 subareas based primarily on transmission characteristics and constraints: “The subareas have been defined solely based on transmission interfaces that are relevant to both reliability and congestion concerns.” These subareas do not necessarily conform to political or utility boundaries.

National Grid USA (2000) owns some of the transmission assets in New England. Its report is less a detailed plan for New England and more an overview of likely transmission needs in the future. The report examined the period 2001 through 2005 in terms of demand projections, generation, the relationship of generation to demand, transmission-system topology (major zones and interfaces), transmission performance (system power flows), capability (transfer limits and congestion costs), and transmission-system opportunities.

The chapter on opportunities is especially interesting because it shows where within New England new generator interconnections “would alleviate or exacerbate congestion on the transmission system.” As Figure 4 shows, locating generators in Boston or southwest Connecticut would relieve congestion, whereas locating generators in Maine, northern Vermont or New Hampshire, Rhode Island, or southeastern Massachusetts would worsen congestion. Information like that shown in Figure 4 should help guide market decisions on new generation and load-management programs, as well as possible merchant-transmission projects.

Provision of information on the current and expected future state of the transmission system and the costs of using that system could reduce what North American Electric Reliability Council (NERC) (2001) sees as “inefficient transmission expansion [caused by the] uncoordinated siting of generation and the development of transmission projects.”

Figure 4. National Grid USA's assessment of the best and worst locations within New England to locate new generating units.



The initial assessment conducted by American Transmission Company (2001) divided its region into five subareas. Like ISO New England, ATC defined these zones on the basis of transmission “system topology, load characteristics, load density and existing generation.” ATC plans to revise the boundaries of these zones if and when bulk-power flows and conditions change. Its initial plan presents several proposals for transmission additions within each zone for 2002, 2003, 2004, and between 2005 and 2010, based on load-flow simulations conducted for 2002, 2005, and 2010.

The Western Governors’ Association (2001) issued a conceptual plan for the Western Systems Coordinating Council.

The plan is conceptual in that it looked at broad regional needs and not at local transmission needs. The report noted important limitations in current transmission plans and the associated planning processes:

The current transmission planning process is fragmented, based on utilities’ individual forecasts of needs and specific interconnection requests from new generation.

At best, coordination occurs on a subregional basis. The current planning process is reactive, rather than forward looking. There is a wide gap between evolving merchant needs on the resource side (regional) and existing grid plans (local or sub-regional) on the transmission side. Planning assumptions are based primarily on local traditional resources and give little consideration to remote and non-conventional resources.

This western analysis considered two generation scenarios to the year 2010. One involves gas-fired generation built close to load centers and the other includes coal, wind, geothermal, and other generation located in remote areas. In the first scenario, little new transmission is needed between 2004 and 2010. In the second case, transmission investments of \$8 to \$12 billion are needed to support 23 GW of new remotely located generation.<sup>3</sup>

<sup>3</sup>This works out to a transmission investment of more than \$400 per new kW of remote generation, a very high cost. If new coal and wind generation costs about \$1000/kW, the supporting transmission would add 40% to the initial cost. By comparison, the new transmission planned for the Pennsylvania-New Jersey-Maryland Interconnection (PMJ, 2001b) region (\$720 million to connect 27,500 MW of new generation) is expected to cost only \$26 per new kW of generation. Part of this cost difference occurs because the distances between generation and load centers are much greater in the west than in the mid-Atlantic region.

Because the Bonneville Power Administration has built no major transmission facilities since 1987, it has a substantial backlog that it is now addressing (VanZandt, 2001). Experts from eight electric utilities in the Pacific Northwest reviewed the first nine projects that BPA proposed, at a total cost of \$615 million (Infrastructure Technical Review Committee, 2001). This largely qualitative review examined, for each of the nine projects, the limiting outages to be addressed by the project, the expected local and regional benefits from the project, various risks associated with the project, a project description, and alternative transmission projects that could address the limiting outages. The review also includes an appendix on risk and uncertainty that outlines the kinds of risks facing new transmission projects, including adequacy requirements, congestion relief, changes in electric-industry structure, and over- vs under-building.

Some recent plans are more limited in scope than the ones discussed above. Often, the plans do not fully integrate planning for reliability with planning for commerce. Because some entities have received so many generator-interconnection requests, their plans are dominated by the specific projects required to connect these new generators to the grid. Correspondingly, the plans do not anticipate possible problems that might occur in the future as a consequence of load growth; generator retirements; other new generators being built within the control area; or additional bulk-power transactions into, out of, or through the control area. In particular, these plans generally do not provide sufficient guidance to market participants on desirable locations for new generation, load-reduction programs, or merchant transmission. These plans are more reactive than proactive, in part because transmission planners do not have enough time to develop plans that look out several years and offer guidance on where to locate new generators. Instead, the planners are often overwhelmed with requests for new generation interconnections. The Bonneville Power Administration (BPA, 2001) wrote:

BPA has received requests for transmission integration studies for more than 13,000 megawatts of new generating capacity at sites around the Northwest. More are pouring through the door. In just the last two weeks, BPA has received eight formal requests for studies on integrating new combustion turbines totaling 3,850 MW. ... The Transmission Business Line is informing developers that it will take at least nine to 12 months to complete the required studies.<sup>4</sup>

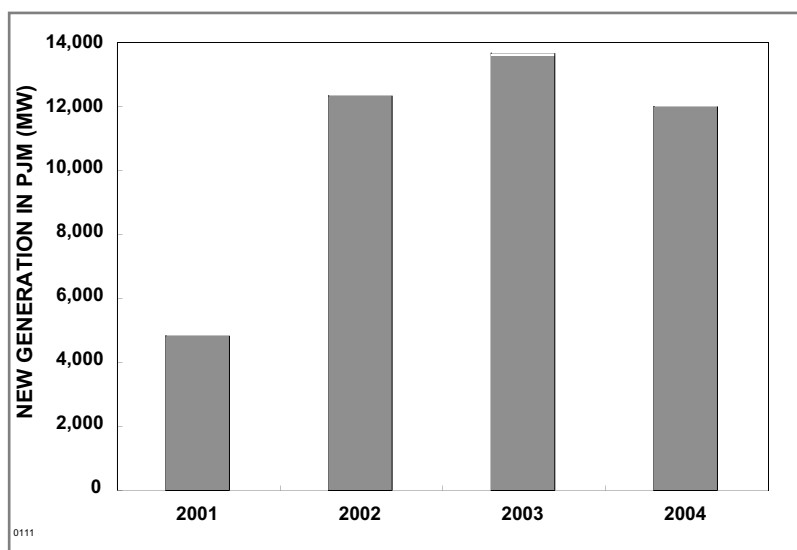
As of March 2001, PJM had received more than 250 generator-interconnection requests, organized into seven queues. The first five queues include 40 GW of new generation to be completed between 2001 and 2004, enough to add more than two-thirds to PJM's current generating capacity (Figure 5). Similarly, ISO New England had, as of Spring 2001, a queue with 40 GW of new generation, far more than the region's peak demand of 23 GW.

Perhaps because of the many interconnection requests PJM has received, its plan, although massive in length and detail, appears to lack any overall purpose. The plan includes two baseline assessments, the first of which analyzes compliance with regional reliability standards from 2001 through 2006 assuming no new generating units are built. The second baseline plan examines, in a similar fashion, the years 2002 through 2007 assum-

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<sup>4</sup>The Tennessee Valley Authority faces a similar situation. It has received applications from independent power producers for 90,000 MW of new generation, more than three times the amount of existing generation (Whitehead, 2001). TVA would need an extra 50 system planners to clear the backlog of interconnection studies associated with all these new generators.

Figure 5. Planned generating capacity in the PJM area.



ing all new generation in Queue A<sup>5</sup> is built. Separately, PJM presents all the interconnection studies associated with the new projects in Queues A, B, and C. In August 2000, the PJM Board approved the Queue A construction projects, with an estimated cost of \$300 million; in June 2001, the Board approved the projects in Queues B and C, estimated to cost an additional \$420 million.

This review of recent transmission plans shows tremendous variation. No single plan encompasses all the elements of a good transmission

plan, as discussed in the section on Proposed Planning Process. Several factors explain the lack of key elements in many plans: (1) the dramatic changes in the U.S. electricity industry raise new issues for transmission planning, (2) the data and analytical tools to address these new issues have not yet been developed, (3) the ISOs are new entities that are still expanding their staffs, (4) the authority and responsibilities of the ISOs and other regional entities are not yet clear, and (5) the planning staffs are very busy responding to generator-interconnection requests. NERC (2001) recently noted that “these complex and rapidly evolving requirements are overwhelming the transmission planning process such that there is not enough time to develop optimal transmission plans.”

## Review of RTO Transmission Planning

The RTO filings of October 2000, required by FERC’s Order 2000, pay little attention to Function 7 on transmission planning and expansion. The need to resolve other RTO issues—such as governance, regional scope and membership, and transmission-cost allocation and revenue requirements—dominated the pre-filing deliberations. Perhaps because of these factors, FERC (1999) gave the RTOs three years after becoming operational to meet the requirements of Function 7.

The GridFlorida (2000) Planning Protocol calls for an “open and inclusive process” conducted by the RTO and supported by a Transmission Planning Committee that will provide “advice and input regarding the planning process” to the RTO. The protocol deals with regional planning; local planning; generation interconnection; data bases; standards for planning, design, and construction; transmission construction; and the role of reliability organizations and the Florida Public Service Commission in the planning process.

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<sup>5</sup>PJM sorts generator interconnection requests into queues depending on when the request was formally made. The August 2001 PJM plan includes Queues A, B, and C, with a total of 27,500 MW of new generation. Although the use of queues may be fair to generators, its application is controversial because it may increase overall electricity costs. For example, some merchant generation projects, although far down in the queue, might help solve transmission problems and, from a societal perspective, should be expedited.

Although the GridFlorida proposal says much about the planning process, it contains few details on the substance of what a transmission plan should contain. While the protocol mentions “market solutions” it does not define the term and does not explain how they are to be identified, assessed, and implemented if found to be cost effective. Similarly, the protocol mentions “alternative solutions” but does not indicate what these alternatives might be, how they are to be compared with transmission solutions, and how they will be implemented.

The RTO West plan (Avista Corp. et al., 2000) “anticipates that RTO West’s approach [to transmission planning] will evolve over time.” The initial plan anticipates transmission expansion for two purposes: (1) “for reliability of service to load” and (2) “to relieve congestion.” As noted elsewhere in this paper, distinguishing between reliability and commercial needs for new transmission is very difficult and perhaps a distraction. With respect to relief of congestion, RTO West anticipates a “market-driven expansion mechanism,” which, in principle at least, should reduce the need for RTO West to develop its own plan in this area.

Attachment P (Description of RTO West Planning and Expansion) focuses on decision-making authority: who decides what facilities are to be built and who pays for these investments. The Attachment commits RTO West to develop:

- (1) criteria to be applied by RTO West in determining the level of transfer capability that should be maintained from existing facilities, (2) transmission adequacy standards, (3) further definition of the market-driven mechanism [for transmission expansion], (4) the [new-transmission-cost] allocation procedure, including objective criteria, (5) interconnection standards, and (6) the details of the relationship/participation of RTO West with appropriate interconnection-wide and regional reliability organizations.

The Alliance RTO (American Electric Power Service Corp. et al. 2000) proposal is included in its Attachment H: Planning Protocol. The RTO is responsible for “coordinating” the planning rather than for doing the planning itself. (Some might question whether a “coordinated” plan is truly an integrated, regional plan or merely a collection of plans prepared by individual transmission owners.) The RTO’s Reliability Planning Committee will be “the vehicle through which coordinated reliability planning activities will be conducted.” RTO staff and representatives from each transmission owner and local distribution utility will be members of this committee, but not other market participants. This committee will be responsible for the planning models and data, reviewing and approving planning studies, determining the need for system expansion to meet reliability needs and transmission-service requests, participating in NERC and regional reliability processes, and coordinating transmission planning and expansion with other RTOs. The committee will produce a 10-year plan every year. The RTO’s Planning Advisory Committee “will provide a forum for stakeholders and interested parties to have input in the planning process.” With respect to transmission projects intended to reduce congestion, the Alliance RTO “will encourage market-driven operating and investment actions....”

The proposal from the New England Transmission Owners et al. (2001) builds on the experience with ISO New England. It envisions a binary RTO with a nonprofit ISO and a for-profit independent transmission company (ITC). The proposed three-phase planning process “combines the knowledge and objectivity of ISO-NE

[ISO New England] with the strengths of an investor-owned business focused on transmission....” The process consists of the following steps:

- The ISO will lead a needs assessment, which will integrate data and projections on regional loads, generation (existing, planned retirements, and potential additions), transmission, and inter-control area transactions to forecast the region’s needs for additional transmission. The needs assessment will be consistent with regional reliability planning standards, address congestion costs, and consider transmission-system performance.
- The ITC will develop a Regional Transmission Facilities Outlook, which will identify transmission alternatives that may be needed based on a range of plausible scenarios.
- Finally, the ISO will assess the ITC’s Outlook and approve a regional plan. This assessment will consider other alternatives proposed by the ISO and stakeholders. The ISO review will provide “a check that the Outlook is not biased in favor of transmission solutions at the expense of generation or other market-based solutions.” “The decision to proceed with [transmission projects] will be made by the market [participants] for market based proposals (including merchant transmission) and by the ITC for regulated transmission proposals.”

This review of some RTO filings suggests that much work remains to be done by the RTOs to develop comprehensive and meaningful transmission-planning processes. Unfortunately, progress has been slow during the past several months. One RTO posted a progress report on its website in August 2001 that its “... planning and expansion principles are still under discussion....” Deciding on a specific transmission-planning approach is difficult in some regions because the participants cannot agree on whether transmission investments should be driven by the market participants or by reliability requirements. In the former case, generator owners, large customers, and private investors might pay for new facilities built as merchant projects, while in the latter case the transmission owners (and ultimately, all retail customers), in response to RTO plans, would pay for such projects through a centralized process.

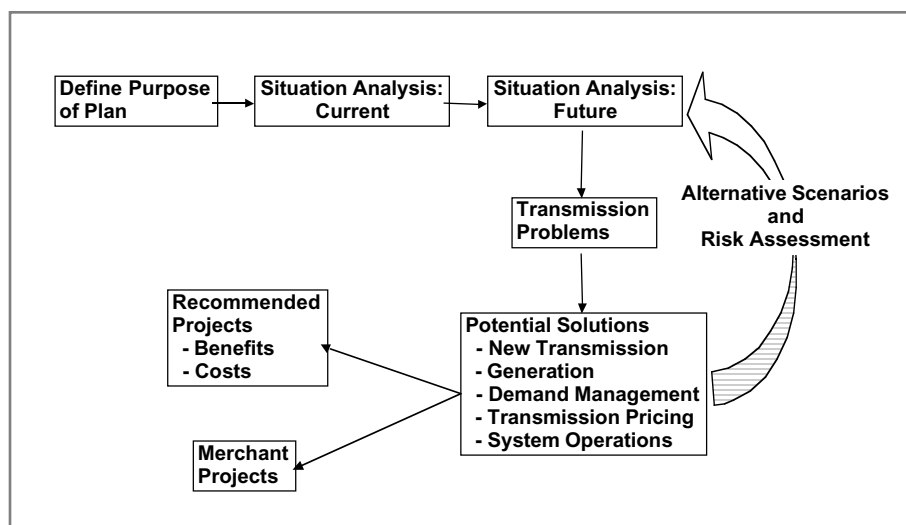
## Proposed Planning Process

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As noted above, transmission planning today is much more complicated, and perversely, much more uncertain, than it was several years ago. Based on our review of several recent transmission plans, we offer a suggested RTO transmission-planning process (Figure 6), the results of which should include broad consensus on new transmission and nonwires projects that are needed and that get built in a timely and cost-effective fashion.

Several of the activities summarized below are covered in greater detail in the following section. Our proposed process begins with a clear identification of the purpose of the transmission plan (Step 1), followed by a comprehensive assessment of the current regional situation, encompassing both operations and markets (Step 2). This situation analysis provides a firm basis for discussing future conditions, problems, and potential solutions. Steps 3 and 4 involve projections of likely conditions several years into the future and an identification of transmission problems that might occur under these postulated future conditions. Steps 5 and 6 assess various transmission and nontransmission alternatives that might solve the problems identified in Step

Figure 6. Outline of proposed RTO planning process.



est groups (e.g., generators, transmission owners, load-serving entities, distribution utilities, retail customers, and state regulators) represented in the development and review of this plan? How does the plan reflect the market design in that region (e.g., the number and types of markets for energy, installed capacity, ancillary services, and congestion)? How were the practical limitations of siting and project financing addressed in the plan (e.g., did the planning process consider nontechnical as well as technical issues, who will pay for transmission projects)? To what extent is the plan intended to motivate market solutions to transmission problems?

**Step 2.** Describe the current situation, covering bulk-power operations (both generation and transmission), wholesale markets, and transmission pricing. What problems (e.g., reliability, congestion, losses, generator market power), if any, occur that are caused by limitations in the transmission system? What transmission projects are under construction or planned for completion within the next few years to address these problems? What are the estimated costs and benefits of these projects, individually and in aggregate? What entities are expected to benefit and to pay for these projects? Explain the computer models used to analyze transmission conditions and the limitations of these models (analytical approximations).

**Step 3.** Describe the bulk-power system as it is expected to exist in the future (e.g., five and ten years). What are the levels, patterns, and locations of loads? Describe the region's fleet of generating units, including locations, capacity, and operating costs (or bid prices). What are the likely effects of new generation facilities on interconnection requests, the overall transmission system, and the costs of new transmission construction? What transmission-pricing methods might be used to recover the costs of capital, losses, and congestion? Describe the transmission flows within the region as well as the flows that occur into, out of, and through the region. Given the many uncertainties that affect future fuel

4. Finally, Step 7 summarizes the results of the analyses conducted in the prior steps and recommends specific projects to address the transmission problems discussed in Step 4.

**Step 1.** What is the purpose of this transmission plan?<sup>6</sup> Who developed it? In response to what requirements? How were various inter-

<sup>6</sup>These purposes could include maintenance of reliability, promotion of competitive electricity markets, support for development of new generation, promotion of economic growth, creation of new jobs, and so on.

<sup>7</sup>The results of Steps 2 and 3 should be sufficiently detailed that other parties can assess for themselves market solutions to solve these problems (e.g., those discussed in Step 6).

prices, loads, generation, transmission and its pricing, and market rules, create various scenarios or sensitivities that can be used subsequently to analyze potential problems and transmission improvements (Steps 4 and 5).<sup>7</sup>

- Step 4.** What transmission problems, both reliability and commercial, are likely to exist given the future conditions (scenarios) developed in Step 3?<sup>8</sup> What other problems might exist for which transmission could be applied (e.g., generator market power caused by a restricted geographical scope of wholesale markets, limited fuel diversity caused by insufficient transmission facilities to remote locations with fuel, such as coal and wind)?
- Step 5.** What transmission facilities might be added to the current system to address the problems identified in Step 4? What effects would these facilities have on compliance with reliability standards, commercial transactions, losses, and overall regional electricity costs (generation plus transmission)? Can recent technological advances in transmission equipment and software be applied? Do they capture potential economies of scale associated with building (ahead of need) larger lines than currently needed? Do these proposals address the potential for generators to exercise market power in wholesale electricity markets?<sup>9</sup> What are the likely capital costs of these transmission additions? How do the costs and benefits of individual projects, as well as groups of projects, compare with each other? Can any of these transmission projects be built on a merchant (i.e., for profit and unregulated) basis? What kinds of risk assessment were conducted in developing recommendations on these new transmission projects?<sup>10</sup> How were these risks addressed in the plan, including the risks of over- vs under-building transmission?<sup>11</sup> Should certain transmission facilities be built to guide current and future decisions on the locations of new generating units and the locations and types of demand-management programs; that is, should transmission planning be proactive rather than reactive?
- Step 6.** What nontransmission alternatives (including suitably located generation and price-responsive load programs as well as alternative transmission-pricing schemes<sup>12</sup>) might be deployed to address the problems identified in Step 4? These alternatives could also include changes in system-operations, such as remedial-action schemes. To what extent can these generation, demand-side, and pricing alternatives address the problems for which the transmission facilities suggested in Step 5 were pro-

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<sup>8</sup>These problems could appear as real-time congestion, denial of requests for service, or curtailment of approved transactions. They could also include operational difficulties caused by aging and obsolete equipment that should be replaced to reduce forced and maintenance outages or increase functionality.

<sup>9</sup>It may be very difficult analytically to estimate the kinds of strategic bidding behavior that might occur. Such behavior will be a strong function of the RTO operating and market rules as well as the physical infrastructure (amounts and locations of generation, transmission, and load).

<sup>10</sup>Uncertainties are much greater than in the past. Today, they include load shape and levels, generator locations (new construction and retirements), market operations, market prices for energy and ancillary services, transmission pricing (including locational pricing for losses and congestion), patterns and levels of commercial transactions, weather, fuel price volatility, and new generation and transmission technologies.

<sup>11</sup>For example, consider the risks associated with cost recovery for a new transmission line needed to connect a new generator to the grid. This risk could be eliminated by requiring the generation owner to pay the capital costs up front rather than through rates over a 20-year cost-recovery period.

<sup>12</sup>Such pricing schemes should encompass access charges as well as charges for congestion and losses.

posed? What are the expected costs to the transmission system of these nontransmission alternatives (which may not reflect the total costs of these generators and/or demand-management programs)? Based on the differences in characteristics and the differences in costs and benefits, recommend either transmission or nontransmission solutions to the problems identified in Step 4. Where no solutions are offered, indicate why. (Presumably, the expected status quo should continue if the costs of solving a problem exceed the benefits of doing so.)

**Step 7.** Based on the foregoing analyses, recommend transmission pricing, generation-location decisions, demand-management programs, and construction of new transmission facilities. If market participants do not propose the solutions analyzed in Steps 5 and 6, recommend those transmission facilities (from Step 6) that should be built under traditional regulation. Summarize the benefits and costs of these proposed projects, both singly and in aggregate. Can the projects ultimately be approved and built in a timely fashion? Can they be financed? Will these projects be undertaken by market participants acting in their own interest, or must the RTO require their construction and ensure that customers at large pay for them?

Table 2, based on this 7-step process, identifies key ingredients of a successful transmission planning process and plan.

**Table 2. Checklist of important characteristics of a transmission plan**

<input type="checkbox"/>	Public involvement throughout planning process
<input type="checkbox"/>	Broad range of alternatives considered, including suitably located generation and demand-management programs, new transmission technologies, and various transmission-pricing methods
<input type="checkbox"/>	Effects of transmission on generator market power
<input type="checkbox"/>	Effects of transmission on compliance with reliability standards, both planning and operating
<input type="checkbox"/>	Effects of transmission on congestion costs
<input type="checkbox"/>	Comprehensive risk assessment of transmission plan(s)
<input type="checkbox"/>	Proactive, rather than reactive, transmission plan (consideration of needs for increased throughput and locational guidance for new resources, not just responses to generator-interconnection requests)
<input type="checkbox"/>	Development of a practical and robust, rather than a theoretically optimized, transmission plan
<input type="checkbox"/>	Support for projects built through competitive-market mechanisms
<input type="checkbox"/>	Timely completion of the plan

# Key Transmission Planning Issues

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## Planning Criteria: Reliability and Commerce

Traditionally, vertically integrated utilities planned their transmission systems to: (1) meet North American Electric Reliability Council (NERC) and regional-reliability-council reliability requirements and (2) ensure that the outputs from the utility's generation could be transported to the utility's customers. (Utilities sometimes built transmission lines for economic reasons; for example, to provide access to cheaper power in a neighboring system or to export surplus power.) Today, transmission systems are called on to do much more. They must serve dynamic and rapidly expanding markets in which the flows of power into, out of, and through a particular region vary substantially over time. As a consequence, transmission planners may need to look beyond the NERC Planning Standards in assessing alternative transmission projects and also consider enabling competition to occur over large geographic regions (NERC 1997). A market-focused approach might seek to reduce the number of times transmission-service requests are denied and generation must be redispatched to avoid congestion. Where congestion (locational) pricing is used, this goal is met by reducing congestion costs (discussed below). Congestion pricing might reduce the distinction between reliability and commerce by explicitly pricing reliability.

Many industry experts believe that the distinction between reliability and commerce in transmission planning is increasingly irrelevant. Reliability problems (e.g., a line that would become overloaded during a contingency) are also commercial problems that affect different market participants differently (e.g., flows are reduced on the line in question, which means that the output from cheap generators must be reduced and the output from expensive generators must be increased). Conversely, certain commercially desirable flows may be restricted because of reliability problems that would otherwise occur. Equally important, these people believe that transmission serves a vital enabling function, permitting the purchase and sale of energy and capacity across large regions and, in the process, reducing problems associated with generator market power.

Some experts believe that the distinction between reliability and commerce is important. Not all reliability problems have commercial implications, they noted. Some local problems (e.g., low voltages close to load centers) are related more to reliability than to commerce. The solution to such reliability problems might be the addition of capacitors to serve local loads regardless of whether the generation source is near or far. The distinction may be important in determining who pays for the project, with reliability projects paid for by all grid users but commercial projects paid for only by those transmission customers who benefit from the project. Of course, deciding who does and does not benefit from a project can be difficult and contentious. The Pennsylvania-New Jersey-Maryland Interconnection (PJM) (2001a) baseline plan focuses on reliability: "Transmission constraints on market dispatch are economic constraints. Economic constraints are not considered violations of reliability criteria as long as the system can be adjusted to remain within reliability limits on a pre-contingency basis."

## Economies of Scale

It is generally cheaper per megawatt of capacity to build larger transmission lines (Table 3). For example, the cost per MW-mile of a 500-kV transmission line is about half that of a 230-kV line. Higher-voltage lines

also require less land per MW-mile than do lower-voltage lines (right side of Table 3). A 500-kV line requires less than half the land per MW-mile of a 230-kV line.

Both of these factors argue for overbuilding lines rather than trying to size lines to exactly match current and short-term forecast needs. (Overbuilding includes the use of larger conductors, construction of larger towers that can carry more than one set of circuits, and the use of higher-voltage lines.) Overbuilding a line now will (1) reduce long-term costs by avoiding the much higher costs of building two smaller lines and (2) reduce the delays and opposition associated with transmission-line siting by eliminating these costs for the now unneeded second line.

**Table 3. Typical costs, thermal capacities, and corridor widths of transmission lines**

Voltage (kV)	Capital cost <sup>a</sup> (thousand \$/mile)	Capacity (MW)	Cost (million \$/GW-mile)	Width <sup>b</sup> (feet)
230	480	350	1.37	100
345	900	900	1.00	125
500	1200	2000	0.60	175
765	1800	4000	0.45	200

<sup>a</sup>These estimates are from Seppa (1999) and include the costs of land, towers, poles, and conductors. We increased these estimates by 20% to account for the costs of substations and related equipment.

<sup>b</sup>These estimates are from Pasternack (2001).

On the other hand, the lumpiness of transmission investments (e.g., one can build a 345-kV line or a 500-kV line but not a 410-kV line) can complicate decisions on what to build and when. Also, a large transmission line may impose more of a reliability burden on the system than do several smaller lines. Indeed, if a new, large line becomes the largest single contingency, contingency-reserve requirements might increase in the region. And, opposition might be greater to a 500-kV line than to a 345-kV line because the former line has taller towers and requires more land.

## Congestion Costs

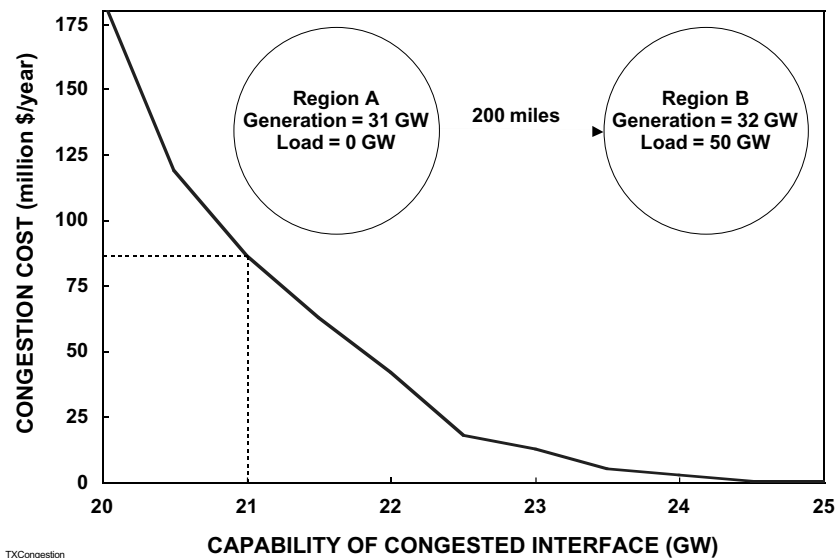
Decisions on whether to build new transmission are complicated by uncertainties over the future costs of congestion. (To some extent, the prices of firm transmission rights show how the market values certain transmission paths.) These uncertainties relate to load growth, the price responsiveness of load, fuel costs and therefore electricity prices, additions and retirements of generating capacity and the locations of those generators, the exercise of market power by some generators, and transmission pricing. The ISO New England (2001) analysis, summarized in Figure 3, shows this complexity very well. Analysis conducted for the New York ISO showed that the large number of proposed generating projects in or near New York City and Long Island “would reduce the level of congestion observed on the...bulk power system, with the biggest congestion decreases occurring in New York City and on Long Island” (Sanford, Banunarayanan, and Wirgau, 2001).

We developed a simple hypothetical example to explore these issues and their complexities and interactions. This example involves two regions, A and B, separated by 200 miles. Region A contains 31 GW of generating capacity and no load. Region B contains 32 GW of generating capacity and 50 GW of load. Both regions contain a wide range of generating capacity, with running costs (or bids) that vary from zero to almost \$160/MWh. The load in Region B ranges from 20 to 50 GW, with a load factor of 63%.

We calculated the cost of congestion as the difference between (1) the cost of generation (including generators in both regions) to serve the load in Region B when transmission capacity between the two regions is limited, and (2) the cost of generation when transmission capacity between the two regions is infinite. The generation costs in both cases are calculated for every hour of the year.

Figure 7 shows the cost of congestion as a function of the transmission capacity connecting the two regions. With 21 GW of transmission capacity (the baseline in this example), electricity consumers in Region B pay \$87 million a year because of congestion. As the amount of transmission capacity increases, the cost of congestion declines because the number of hours that congestion occurs and the price differences between A and B decline. However, as shown in Figure 7, this decline is highly nonlinear, with each increment of transmission capacity providing less and less economic benefit. Expanding transmission capacity from 20 to 21 GW lowers the cost of congestion \$99 million/year, expanding capacity from 21 to 22 GW saves \$44 million, and expanding capacity from 22 to 23 GW cuts costs by only \$29 million.

*Figure 7. The annual cost of congestion as a function of transmission capability between hypothetical regions A and B.*



The relationship between the benefits of adding transmission capacity between A and B to reduce congestion costs and the costs of doing so are highly nonlinear because of (1) nonlinearities in congestion costs, (2) economies of scale in transmission investments, and (3) the lumpiness of transmission investments. For this example, if the goal is to increase capacity by 0.5 GW, it makes sense to build either two 230-kV lines or one 345-KV line, but not a 500-kV line. On the other hand, it is most cost effective to use 500-kV lines

when expanding capacity by 1 GW or more. Indeed, the benefit/cost ratio for 230-kV lines increases in going from an addition of 0.5 to 1.0 GW, but then declines as more capacity is added. On the other hand, the benefit/cost ratio is more than 2 for the addition of a 500-kV line to expand capacity by 1.5 or 2.0 GW.

What happens to these costs and benefits if additional generating capacity is built in Region B, close to the load center? Adding 0.5 GW of capacity with a running cost of \$30/MWh reduces congestion costs by

\$19 million/year. Adding 2 GW of such capacity reduces congestion costs by \$59 million/year. If the new generating capacity added to Region B had a running cost of \$57/MWh, its congestion-reduction benefits would be only \$14 and \$35 million/year for 0.5- and 2-GW additions, respectively. These benefits are about two-thirds of those that would occur with new capacity at \$30/MWh. Clearly, building new generation in Region B would undermine the economics of adding transmission capacity between regions A and B.

The congestion-reduction benefits of each additional MW of generating capacity are less than the benefits of earlier additions. This effect is especially pronounced as the bid prices of the new units increase. For the more expensive of the two units there is no benefit from adding more than 1.5 GW of generating capacity in Region B because other generators are less expensive. Once again, the results are highly nonlinear.

If loads grow at 2% a year, the annual cost of congestion (assuming no additions to either generating or transmission capacity) increases from \$87 million in the initial year to \$125, \$162, and \$250 million in the second, third, and fourth years. Such increases in load make transmission investments substantially more cost-effective. If loads respond to prices, such that loads are higher at low prices and lower at high prices, congestion costs would be reduced. In this example, as the price elasticity of demand increases from 0 to 0.02, 0.04, and 0.08, congestion costs are reduced from \$87 million to \$48, \$25, and \$7 million a year. For the ranges in load growth and price elasticity considered here, congestion costs vary from \$7 to \$250 million a year when the amount of transmission capacity between the two regions is 21 GW. Making decisions on how much money to invest in equipment with lifetimes of several decades is difficult in the face of such uncertainties about future load growth; customer response to dynamic pricing; and the amounts, locations, and running costs of new generating units.

The discussion so far has focused on the benefits of reducing congestion. But not all market participants benefit when additional transmission is built to relieve congestion. In particular, loads on the low-cost side of the constraint and generators on the high-cost side of the constraint lose money when congestion is reduced. For example, a generator in Region B with a bid price of \$42/MWh would earn \$6.9/kW-year when the transmission capacity between regions A and B is 20 GW. Expanding transmission capacity to 21 or 22 GW would reduce that generator's earnings to \$4.6 and \$3.7/kW-year, reductions of 33% and 46%, respectively. Such large prospective losses would likely engender substantial opposition to efforts to reduce congestion. (If Region A had loads that enjoyed the benefits of Region A's low-cost generation, those loads would also oppose efforts to reduce congestion.)

Finally, investors considering additional generation in Region B may worry that future construction of a new transmission line between A and B would undercut the value of their new generation.

## **Generation and Load Alternatives**

The Department of Energy Task Force on Electric System Reliability (1998) recommended that RTOs "ensure that customers have access to alternatives to transmission investment including distributed generation and demand-side management to address reliability concerns and that the marketplace and the [RTO's] standards and processes enable rational choices between these alternatives."

Transmission planners can encourage nontransmission alternatives in two ways. The simplest method is to provide transmission customers with information on current and likely future congestion costs. Such information—coupled with locational pricing for congestion and losses—on the costs and benefits of locating loads and generation in different places could motivate developers of new generation to pick locations where energy costs are high, thereby reducing congestion costs. Similarly, such information could motivate load-serving entities to offer load-reduction programs to their customers in those areas where energy prices are high because of congestion. For example, the National Grid USA (2000) transmission plan included a map of New England (Figure 4) showing areas where new generation would worsen congestion and areas where new generation would reduce congestion. An alternative approach to the provision of information only is to pay for nontransmission alternatives. With this approach, the RTO would first prepare a transmission plan. This plan would likely include one or more major transmission projects (new lines and/or substations). Next, the RTO would issue a request for proposals for alternatives and then review the proposals to see if they were less expensive than the original transmission project and provided the same or better reliability and commercial benefits that the transmission project would. Ultimately, the least-cost solution to the identified transmission problem would be acquired by the RTO and recovered through transmission rates.

Appropriately comparing transmission to load or generation, however, is difficult because they differ in construction leadtimes, project lifetimes, availability, capital and operating costs, market type, and technical applicability:

- **Lifetimes**—Transmission investments are long-lived (30 to 50 years). Generators typically have shorter lifetimes, and load-management projects may have much shorter lifetimes (e.g., if a building is extensively remodeled, the load-management systems may be removed and replaced with alternative systems for lighting, heating, cooling, and ventilation). The longer lifetimes of transmission projects enhance confidence in their ability to provide the needed service for many years; however they reduce flexibility to respond to changed circumstances in the future.
- **Availability**—Transmission equipment typically has very high availability factors, much higher than those for either generation or load.
- **Capital and operating costs**—Although the capital costs of transmission can be high, operating costs are very low. The operating costs for generators are high and depend strongly on uncertain future fuel prices. The tradeoff here is between high sunk costs (once the transmission project is completed) against uncertain operating costs for generation and load management.
- **Type of market**—The returns on transmission investments are regulated, today primarily at the state level and in the future primarily by FERC. The profitability of generation investments, on the other hand, is determined largely by competitive markets. Comparing costs (e.g., economic lifetimes and rates of return) between regulated and competitive markets is difficult.
- **Technical applicability**—Nonwires resources cannot always solve the problems at which the transmission investment is aimed (e.g., transient stability or the need to replace aging or obsolete transmission equipment). Also, connection of the resource to the grid may impose new costs on the system (e.g., if system-protection schemes must be upgraded).

The difference in lifetimes between the transmission project and its alternatives raises the issue of whether the alternatives should be assessed against the cost of deferring the transmission project for several years or against the full cost of displacing (eliminating the need for) the transmission project. If the transmission project will likely be needed in any case, although at a later date, the deferral approach makes sense.

Although the concept of encouraging competition between transmission investments and generation and load alternatives is appealing, implementation can be difficult. The Tri-Valley project, proposed by Pacific Gas & Electric in northern California, illustrates these difficulties. The project involves the construction of new 230-kV transmission lines, construction of new 230/21-kV substations, and upgrading of a substation to 230-kV service. The California ISO issued a request for “cost effective and reliable alternatives... from generation and/or load alternatives to the proposed PG&E transmission project” (Winter and Fluckiger, 2000). Alternatives were required to be available between the hours of 8 am and 1 am for up to 500 hours between April 1 and October 31 each year from 2001 through 2005. The ISO sought call options on about 175 MW. The request was issued in January 2000 with responses due in late March. The ISO received four proposals, all of which it subsequently rejected.

The ISO rejected all four bids because they failed one or more of the evaluation criteria, which involved satisfaction of the ISO’s reliability criteria, commencement date, operating characteristics, ability to provide the proposed services, cost, safety, impacts on markets (in particular, effects on generator market power), and environmental implications. The key reason the bids were rejected is they were substantially more expensive than the transmission project. Also, the transmission project was expected to provide more capacity to the system than the generation and load-management projects.

A year later, when faced with a similar situation, the ISO decided against issuing a competitive solicitation. In this case, the ISO approved construction of the San Diego Gas & Electric Valley-Rainbow transmission project (Detmers, Perez, and Greenleaf 2001). In part because of the electricity crisis California faced, the ISO decided that this project should be considered part of a “broad strategy by the state of California to put into place a robust transmission system to support reliable service to consumers.” The benefits of this 500-kV transmission project would not be realized by generation or load-management alternatives. The proposed transmission line would permit generation from other parts of California, Arizona, and New Mexico to be moved to the San Diego area. The project would also permit new generators being located near San Diego to reach distant markets. Finally, the project would provide local reliability benefits that otherwise would have to be purchased through reliability-must-run contracts. These reliability benefits would occur because the transmission project “integrates San Diego with the rest of the Western Interconnection, providing significant access to a wide variety of resources rather than being limited to the local area resources and the common concerns that they share, such as adequacy of gas supply.”

The limited analysis conducted to date seems to argue against widespread use of suitably located generation and load management as alternatives to some new transmission projects. However, these analyses were conducted primarily by transmission engineers who are more comfortable with transmission and understand transmission better than they do its alternatives. Also, the continued opposition to construction of new transmission facilities requires the electricity industry to look long and hard at possibly viable alternatives.

## New Technologies

Superconductivity, power electronics, information systems, and other new technologies could revolutionize transmission and make it easier to expand the system through merchant, rather than regulated, projects. According to Howe (2001), “Recent advances in materials science offer the prospect of another industry paradigm: one based on robust facilities-based competition in network services, without the environmental and land-use impacts of traditional ‘big iron’ solutions.” Some of these advances include:

- **Superconducting Magnetic Energy Storage**—High-speed magnetic-energy-storage devices that are strategically located in a transmission grid to damp out disturbances. These systems include a cryogenically cooled storage magnet, advanced line-monitoring equipment to detect voltage deviations, and inverters that can rapidly (within a second) inject the appropriate combination of real and reactive power to counteract voltage problems. By correcting for potential stability problems, these systems permit the operation of transmission lines at capacities much closer to their thermal limits than would otherwise be possible.
- **High-Temperature Superconducting cable**—Can carry five times as much power as copper wires with the same dimensions. Although initially applicable to underground distribution systems in dense urban areas, eventually this technology may be used for medium- and high-voltage underground transmission lines. The use of these cables would greatly reduce the land required for transmission lines in urban areas and lessen aesthetic impacts and public opposition.
- **Flexible AC Transmission System (FACTS) devices**—A variety of power-electronic devices used to improve control and stability of the transmission grid. These systems respond quickly and precisely. They can control the flow of real and reactive power directly or they can inject or absorb real and reactive power into the grid. These characteristics provide both steady-state and dynamic benefits. Direct power-flow control makes the devices useful for eliminating loop flows. The very fast response makes the devices useful for improving system stability. Both characteristics permit the system to be operated closer to its thermal limits. FACTS devices include static var compensators, which provide a dynamic source of reactive power; thyristor-controlled series capacitors, which provide variable transmission-line compensation (effectively “shortening” the line length and reducing stability problems); synchronous static compensators, which provide a dynamic source of reactive power; and universal power-flow controllers, which control both real- and reactive-power flows.
- **High-Voltage DC (HVDC) systems**—HVDC lines have several advantages over AC transmission lines, including no limits on line length, which is useful for moving large amounts of power over long distances; reduced right-of-way because of their more compact design; precise control of power flows, eliminating loop flows; and fast control of real- and reactive-power to enhance system stability. The primary drawback of HVDC is the high cost of the converter stations (which convert power from AC to DC or vice versa) at each end of the line.
- **HVDC Light**—This new approach to HVDC uses integrated-gate bipolar transistor-based

valves (instead of thyristor-based valves) in the converter stations. These new valves permit economical construction of lower-voltage lines, which greatly increases the range of applicability for DC lines; involves much more factory construction instead of onsite construction, which lowers capital costs; and provides better control of voltages and power flows. HVDC-light lines have recently been built in Australia and Denmark, and others have been proposed for the United States.

- Real-time ratings of transmission lines—Represent another use of advanced information technologies to expand the capability of existing systems (Seppa, 1999). Such systems measure the tension in transmission lines, ambient temperature and wind speed, or cable sag in real time; the results of these measurements are telemetered to the control center, which then adjusts the line rating according to actual temperatures and wind speeds.

In spite of their wonderful attributes and recent declines in their costs, these technologies are generally too expensive to warrant their widespread use today. (To date, they have been deployed in a few locations, primarily by utilities to improve the performance of their systems.) However, as the technologies are improved and demonstrated, their costs will likely continue to drop enough that they become cost effective. When that day arrives, transmission planning will be simpler, primarily because market participants (rather than regulators or system operators) will be able to decide whether to invest in these systems and will be able to retain their benefits (because some of these technologies use devices that permit direct control of power flows).

## Merchant Transmission

The kinds of new technologies discussed above make it possible for unregulated, for-profit entities to build what are called merchant transmission projects. Under such circumstances, the need for centralized transmission planning is greatly reduced. Three such merchant projects have been proposed in the United States:

- TransEnergie US proposes to build a 330-MW, 26-mile submarine cable under Long Island Sound to connect Connecticut and Long Island. FERC approved the project in June 2000, after which TransEnergie held an open-season subscription for the DC line's capacity.
- The Neptune Regional Transmission System, announced in May 2001, is a set of DC projects to link the northeastern U.S. with eastern Canada. All four phases involve submarine cables. The total project calls for 3600 MW of transfer capability from Canada to the U.S. FERC approved the project in July 2001.
- The TransAmerica Grid, proposed by Black & Veatch and Siemens AG, calls for construction of large mine-mouth coal plants in Wyoming and DC lines to connect this new generation with Chicago and Los Angeles. These transmission lines, about 1000 miles each, would cost \$4.5 billion and would greatly expand the transfer capability between the eastern and western interconnections.

All three of these projects are DC. As noted by Liles (2001):

“...the benefit of DC lies in the ability of the project’s operator to control the flow of power on the line. What you put in is what you get out, net of resistive losses. Loop flow is not an issue. Contrast that with the existing AC network, in which power flows freely throughout the system according to the impedances of the lines.... Physically firm transmission capacity can be bought and sold on a DC line. For DC lines, the contract path is the actual path over which the power flows.”

Such merchant projects are feasible only if the owner can obtain clear property rights to the transmission investment. According to Rotger and Felder (2001), such property rights require the use of “bid-based, security-constrained locational pricing for transmission services” as well as financial transmission rights. The PJM and New York ISOs have such systems in place.

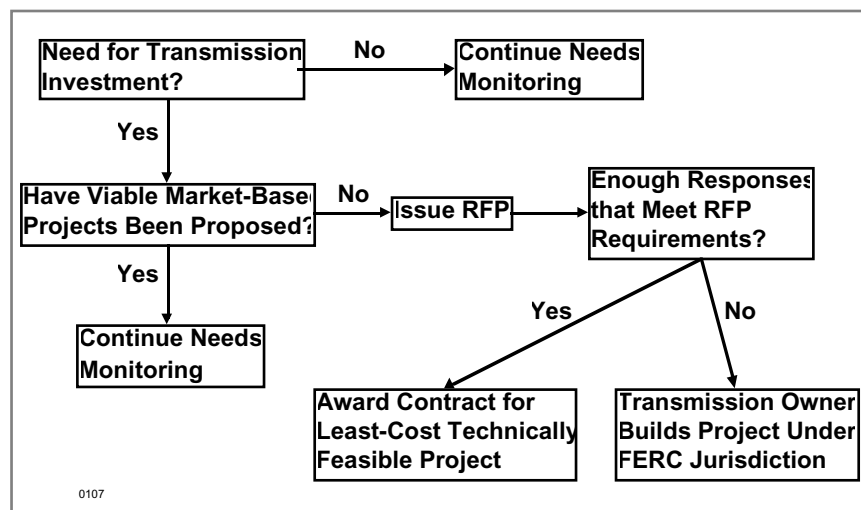
Rotger and Felder (2001) propose a regulatory backstop in case competitive markets do not construct enough transmission to maintain reliability. Their vision of a backstop, however, is quite limited. It calls for the RTO to assess the need for new transmission to meet reliability requirements only, with no consideration of economic projects that might reduce costs to market participants. The RTO, having identified transmission projects needed for reliability, would then issue a request for proposals for such projects (Figure 8).

Although attractive in concept, no merchant transmission projects have yet been built in the United States. It is also unclear whether such projects are viable only where direct control is possible (e.g., with DC lines and other new technologies such as FACTS systems) or whether such projects are feasible for AC systems. If merchant projects are limited to those where control is possible, it is unclear whether such projects will play a major role in expanding North American transmission systems or will play more of a niche role.

## Projections of New Generation and Load Growth

The deintegration of the traditional utility, which encompassed generation, transmission, distribution, and

*Figure 8. Proposed RTO backstop process to be used when competitive markets do not produce enough transmission expansion to meet reliability requirements.*



customer service in one entity, raises two important informational issues for transmission planning. First, from what sources will transmission planners obtain reliable information on the locations, types, capacities, and in-service dates of new generation? Second, what entity will be responsible for developing projections of future load growth?

Historically, utilities reported their plans for new generation to the Energy Information

Administration (EIA) and NERC. Increasingly, however, new generation is being constructed by independent power producers. Although EIA collects data from such entities, long lags can occur between the time a company announces a new power plant and the time it shows up in the EIA system. The Electric Power Supply Association also collects data on power-plant construction plans. Because the Association does not provide details on the status of the project, it is hard to determine the probability that a project will get built and produce power. The probability of unit completion increases as the project moves from initial announcement to applications for siting and on to environmental permits, construction, and completion.

Analogous issues concern projections of future load growth. System operators (ISOs and, in the future, RTOs) monitor and record data on power flows down to the level of distribution substations. But, because of their focus on bulk-power flows and wholesale electricity markets, system operators are unlikely to have data on end-use demand by customer class. The competitive load-serving entities may have such information but are unlikely to want to make such information publicly available. The electricity industry needs to develop a system to collect relevant data on customer electricity-using equipment, load shapes, and load levels and to provide this information to transmission planners (as well as to other entities responsible for maintaining a healthy bulk-power system).

## Recommendations

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As the electricity industry continues its long and complicated transition to a fully competitive state, the requirements for transmission planning are changing and expanding. This paper outlined a proposed planning process that RTOs might adopt in a restructured electricity industry. However, most of the details for this process are not yet developed. Similarly, FERC's requirement in Order 2000 that "the RTO must have ultimate responsibility for both transmission planning and expansion within its region" is largely undefined. These gaps lead to several recommendations for the U.S. Department of Energy (DOE), FERC, and RTOs to consider:

- Provide technical assistance to ISOs, RTOs, regional reliability councils, federal power agencies, and other organizations to develop and demonstrate improved transmission-planning methods. Such methods would feature active public involvement throughout the planning process, comprehensive consideration of nonwires solutions to transmission problems, analysis of the benefits and costs of different solutions under a wide range of possible futures, and a focus on practical solutions that can be readily implemented. DOE could work with the planning staffs at various electricity-industry organizations to develop improved planning processes, analytical tools, and plans. DOE could then widely disseminate the results of these case studies (i.e., through publications, conferences, and workshops) so that others in the electricity industry can learn from these experiences.
- Assist FERC in the development of planning standards that FERC would then use in its review and approval of RTO transmission plans. This activity would add detail to the FERC Order 2000 requirement that RTOs be responsible for planning (Function 7). Based on the case studies described above, DOE could work with FERC staff to define what pub-

lic involvement is required, what data RTOs must make available to market participants on the current and likely future states of the transmission system, what FERC means by “least cost” in its requirement that RTOs be responsible for transmission planning and expansion, and the extent to which planning should be proactive (i.e., guide future investments in new generation and demand-management programs), rather than only react to generator-interconnection requests and load growth. These standards should focus on performance (what is to be accomplished) and not be prescriptive, to permit flexibility within and among RTOs.

- The RTOs, acting under FERC requirements, could ensure that transmission planning and expansion fully comply with NERC and regional planning standards. Such compliance would ensure that transmission systems are adequate and meet reliability and commercial needs.
- The RTOs should identify the transmission-information needs of market participants (including generation developers, load-serving entities, transmission owners, and others) to guide their investment and operating decisions so they are consistent with current and likely future transmission conditions and costs. The information needs of interested stakeholders will vary considerably. Some participants will only want maps showing “good” and “bad” locations for new generation from the perspective of the transmission system, while other participants will want detailed load-flow studies that show voltages and flows throughout the system, under various on- and off-peak conditions. Periodically, such information should be made available to market participants.
- Study the potential role of merchant transmission. DOE, again working with RTOs and other market participants, could conduct a study to determine the extent to which merchant (nonregulated) transmission projects can meet future transmission needs. Among other topics, this study should examine the possibility of extending merchant transmission to AC projects, rather than the DC projects that are the focus of today’s merchant transmission facilities. Another critical issue concerns the meaning of the RTO role as a “backstop” to market solutions. Under what conditions should the RTO build (or pay for) a project that is needed to solve transmission problems that market participants have not, acting on their own, chosen to solve? This study should also address the danger that merchant transmission will “cherry pick” the most profitable transmission projects, leaving the regulated entity (more accurately, transmission customers in general) to pay for the less cost-effective transmission projects that, nevertheless are required for reliability or to connect customers to the system.

## Conclusions

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Maintaining a healthy transmission system is vital for both reliability and commerce. Because electricity is essential to our modern society, public policy should ensure suitable expansion of the nation’s transmission grids. Unfortunately, the historical record shows a clear and long-term decline in U.S. transmission adequacy

(Hirst and Kirby 2001). Specifically, the amounts of new transmission added during the past two decades have consistently lagged growth in peak demand. To make matters worse, projections for the next five and ten years show continued declines in adequacy, although some of the projected need for new transmission may be met by the construction of generating units close to load centers.

To further compound the problem, transmission planning is not keeping pace with the need for such planning. Because transmission owners and ISOs are receiving so many requests for generator interconnections, they are unable to devote the staff resources needed to develop proactive transmission plans. That is, they are focused primarily on preparing the system-impact and facility studies required for these new interconnections. Thus, some transmission plans are little more than compilations of individual generator-interconnection studies.

Because transmission planners have insufficient time and resources, little information is being provided proactively to energy markets on the costs and locations of congestion. Such information could help potential investors in new generation decide where to locate new units. Such information could also help load-serving entities decide what kinds of dynamic pricing and load-reduction programs to offer customers in different locations. More broadly, such information could reduce the need for centralized planning and construction of new transmission facilities.

Because generation and load can serve, in some instances, as viable alternatives to new transmission, transmission plans need to explicitly consider such nontransmission alternatives. Whether the transmission system (i.e., transmission users in general) should pay for these generation and load projects is unclear and hotly contested. At a minimum, transmission planners should provide information (again based on analysis of past and likely future congestion costs) on suitable locations for new generation and load management. In a similar fashion, alternative methods for pricing transmission services (including charges for access, congestion, and losses) would affect transmission uses. These changes in transmission flows would, in turn, affect the need for new facilities. Thus, transmission planning should include assessments of alternative pricing methods to improve efficiency in transmission utilization.

Transmission planning may be too narrowly focused on NERC and regional reliability-planning standards. That is, transmission planning may pay insufficient attention to the benefits new transmission investments might offer competitive energy markets, in particular, broader geographic scope of these markets (which would encourage greater diversity in the fuels used to generate electricity) and a reduction in the opportunities for individual generators to exercise market power. Although some plans consider congestion (either congestion costs or curtailments and denial of service), such considerations are more implicit than explicit. As shown here, congestion costs (both in real time and in forward markets) can provide valuable information on where and what to build.

Advanced technologies offer the hope of better information on and control of transmission flows and voltages. Such improved information and control would permit the system to be operated closer to its thermal limits, thereby expanding transmission capability without increasing its footprint. Thus, new technologies may reduce fights about transmission siting. In addition, these technologies, because they permit control of power flows over individual elements (e.g., DC lines), may make it attractive for private investors to build individual facilities (merchant transmission). Unfortunately, these advanced technologies are still too expen-

sive for widespread application, although some are economic in niche applications.

The separation of generation from transmission and of retail service from transmission poses difficult information problems for transmission planning. Specifically, transmission planners need detailed information on the timing, magnitudes, and locations of new generating units; the developers of these facilities are unwilling to share competitive information until required to do so (e.g., for environmental permits and for transmission-interconnection studies). Planners also need detailed information on the locations and magnitudes of future loads. In a retail-competition world, it is not clear what entities will have the information necessary to produce reliable projections of retail load and whether those entities will be willing to share these projections with transmission planners.

Finally, the economies of scale in transmission investment argue for overbuilding, rather than underbuilding, transmission. It is substantially cheaper per GW-mile to construct a higher-voltage line than a lower-voltage line. The higher-voltage line also requires less land per GW-mile, which should reduce opposition from local landowners and residents. Also, building a larger line now eliminates the need to build another line in several years. This situation can eliminate the need for another potentially bruising and expensive fight over the need for and location of another transmission line. Also, the availability of suitable land on which to build transmission lines can only go down in the future, as population grows and the economy expands. On the other hand, overbuilding can increase financial risks for the transmission owners.

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